Supplemental Evaluation
of
NO_x BART Determination
for
Coal Creek Station Units 1 and 2

September 2012

North Dakota Department of Health
Division of Air Quality
918 E Divide Avenue
Bismarck, ND 58501

Table of Contents

Supplemental Evaluation of
NO_x BART Determination
for
Coal Creek Station Units 1 and 2

I. Introduction

As part of the development of the State of North Dakota's Regional Haze State Implementation Plan (SIP), in March of 2010, the Department finalized and submitted to the U.S. Environmental Protection Agency (EPA) a Best Available Retrofit Technology (BART) determination for nitrogen oxides (NO_x) emitted from Coal Creek Station (CCS) Units 1 and 2. The BART determination was originally submitted to the Federal Land Manager's (FLMs) for their review (consultation) on June 2, 2008. The Department of Interior (DOI) provided comments on August 11, 2008 and the Department responded to those comments on July 16, 2009 (see Appendix J.1.2 of SIP). After making revisions and finalizing the SIP, the Department again consulted with the FLMs on the entire SIP (including the Coal Creek BART determination) in August 2009 (see Appendix J.1 of SIP). The DOI and U.S. Forest Service both provided comments in October 2009 (see Appendix J.1.3 of SIP). The Department's response to those comments was finalized in December 2009 and incorporated into the SIP (see Appendix J.1.4 of SIP). Public comment on the SIP, including the Coal Creek BART determination, was held from December 8, 2009 to January 8, 2010 with a public hearing January 7, 2010. Comments on the SIP were received from the U.S. Environmental Protection Agency (EPA), several environmental groups, concerned citizens, DOI and several of the affected sources. The comments and the Department's response to those comments are included in Appendix F.8 of the SIP.

The Coal Creek BART determination in the March 2010 SIP established a NO_x limit of 0.17 lb/10^6 Btu (30 d.r.a.) for each unit based on combustion controls. Subsequent to this submittal, EPA, during its review, discovered that Great River Energy (GRE) had used a value for ash sales based on the total sales price instead of the amount GRE would receive from the sales. After this discrepancy was discovered, EPA finalized a Federal Implementation Plan (FIP) for regional haze which established a BART limit of 0.13 lb/10^6 Btu (30 d.r.a.) based on selective non-catalytic reduction (SNCR) and combustion controls. Because of the error in GRE's analysis, the Department requested GRE submit a revised BART cost estimate to the Department. On July 15, 2011, GRE submitted its revised BART determination to the Department. Later, through telephone contact with GRE, the Department was advised that GRE planned to submit an entirely new cost estimate for selective non-catalytic reduction (SNCR) and additional information. The following is the Department's understanding of the chronology of events:

Date	Item
July 15, 2011	GRE submits revised cost estimate for SNCR
September 21, 2011	EPA proposes to approve in part and disapprove in part North Dakota's Regional Haze SIP and proposes FIP
November 3, 2011	Department letter to GRE asking that revised analysis be provided by December 21, 2011
November 14, 2011*	Department informs EPA by letter that it will reevaluate the Coal Creek Station BART determination
November 21, 2011	GRE submits revised BART analysis to the Department
December 7, 2011	Department letter to EPA advising it of GRE's submittal and Department's review
January 10, 2012	Conference call with GRE to discuss comments on November 21, 2011 submittal
January 19, 2012	Department letter to GRE with comments to the November 21, 2011 submittal
February 10, 2012	GRE submits revised analysis
February 28, 2012	Department letter to GRE with comments on February 10, 2012 submittal
April 5, 2012	GRE submits revised analysis in response to Department's February 10, 2012 comments
April 6, 2012	EPA publishes final FIP
April 11, 2012	GRE submits revised analysis which updated visibility impact tables
May 21, 2012	Conference call with GRE where Department indicated it did not agree with a baseline of 0.153 lb/10^6 Btu for Unit 2 and there was an error in the Unit 1 cost effectiveness analysis
June 6, 2012	GRE submits revised calculations of cost effectiveness and incremental cost for both units based on the May 21, 2012 comments

*The November 14, 2011 submittal, and subsequent submittals, included a site-specific evaluation of NO_x controls at Coal Creek Station by GRE's technical consultant URS. The submittal also contained an evaluation of the potential for lost ash sales due to the installation of SNCR and the cost of treating or disposing of unmarketable ash. The evaluation was prepared by Golder Associates, another consultant for GRE.

The Department's January 19, 2012 letter included comments regarding the baseline emission rate, questions about the differences between Coal Creek Station and the East Lake Station where 15% of the fly ash is untreatable due to SNCR operation, as well as identifying several calculation errors and inconsistencies. The letter also questioned the accuracy of the visibility improvement tables. GRE's February 10, 2012 resubmittal addressed many of the issues the Department had raised; however, as detailed in the Department's February 28, 2012 comments on this submittal, the Department continued to question the accuracy of the visibility modeling results and the accuracy of some calculations. The Department's February 28, 2012 letter also pointed out some discrepancies and inconsistencies in the documents.

On April 6, 2012, GRE submitted to the Department a revised analysis. However, the Department determined that the GRE analysis did not contain the revised visibility modeling results table. After informing GRE of this issue, a revised analysis with the revised visibility modeling results tables was submitted to the Department on April 11, 2012. The Department's last comments on GRE's revised NO_x BART analysis came during a conference call on May 21, 2012. On that call, the Department told GRE that it did not agree with a baseline emission rate of 0.153 lb/10^6 Btu for Unit 2. The Department also advised GRE of an error in the cost effectiveness calculations for Unit 1. In response to that call, on June 6, 2012 GRE submitted revised cost calculations based on a baseline of 0.201 lb/10^6 Btu for Unit 2 and corrected calculations of cost effectiveness for Unit 1. Based on GRE's revisions, the Department has determined the analysis is complete and the calculations are accurate.

Contained in this Supplemental Evaluation is the Department's analysis of GRE's April 11, 2012 submittal as revised on June 6, 2012.

II. BART Analysis Review

When EPA proposed the FIP, which included NO_x limits for the two units of the Coal Creek Station, they conducted their own BART analysis. The Department has identified five major issues which significantly affect the BART determination for GRE, and which EPA and GRE differ in their analysis of those issues. These issues are:

1) The baseline emission rate to be used in the analysis.
2) The NO_x control efficiency for SNCR.
3) The capital cost of SNCR.
4) The amount of urea required to be fed into the boiler to achieve the desired NO_x reduction.
5) Whether fly ash sales will be lost due to ammonia adsorption onto the ash.

The Department has reevaluated each of these five issues and independently finds and determines the following:

A. Baseline Emissions

The original BART analysis submitted by GRE (December 2007) established a baseline emission rate of 0.22 lb/10^6 Btu for each unit. In GRE's April 2012 submittal, GRE proposed a revised baseline of 0.201 lb/10^6 Btu for Unit 1 and 0.153 lb/10^6 Btu for Unit 2. GRE indicated their Dry Fining™ technology had reduced NO_x emissions to 0.201 lb/10^6 Btu at Unit 1 and LNC3+ combustion technology had further reduced emissions at Unit 2 to 0.153 lb/10^6 Btu.

Regarding GRE's proposed revision of the baseline emission rates, EPA stated in their response to comments set forth in the FIP (77 FR 20927) the following:

"We evaluate potential control options based on baseline conditions, not on ongoing revisions to a facility after the baseline period. It is not reasonable to consider controls installed after the baseline period in determining BART. Such an approach would tend to lead to higher cost effectiveness values for more effective controls and encourage sources to voluntarily install lesser controls to avoid installing more effective BART controls later."

The BART Guidelines (40 CFR 51, Appendix Y) state "The baseline emissions rate should represent a realistic depiction of **anticipated** [emphasis added] annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." It is clear that the baseline emissions are future emissions, not necessarily a past emission rate. Use of past emission rates could overestimate the baseline emission rate. For example, if a source anticipated using a lower sulfur fuel in the immediate future, using past emissions to establish the baseline would clearly overstate the future emissions. Based on the BART Guidelines, the Department has evaluated future operating scenarios as part of the BART determination process (e.g. Stanton Station).

The installation of the Dry Fining™ technology was under development for many years before the Department made its BART determinations in 2010. Dry Fining™ (coal drying and other coal enhancements) along with scrubber improvements was the technology GRE listed for achieving the sulfur dioxide limit in their 2007 BART analysis. Although GRE clearly anticipated using Dry Fining™ technology, no emissions reductions were credited towards the baseline emissions rate in the Department's 2010 BART determination for NO_x. At that time, the effect on NO_x emissions was unknown. Since that time, it has been determined that Dry Fining™ reduced NO_x emissions by 0.02 lb/10^6 Btu on an annual average basis. Because the installation of the Dry Fining™ technology was anticipated as part of the technology selected for BART for sulfur dioxide, and no NO_x emissions reductions were relied on in the 2010 BART determination (the effect was unknown), it is appropriate to take the now known NO_x emissions reductions from Dry Fining™ into account when determining a new baseline emission rate.

The installation of LNC3+ combustion controls was to be installed to meet the 2010 NO_x BART limits established by the Department (SOFA + LNB Option 1). Because this technology was proposed to meet their 2010 NO_x BART limit, it is inappropriate to consider it as part of the baseline after the final BART determination.

Based on the information provided by GRE, a baseline emission rate based on 0.201 lb/10^6 Btu at each unit is appropriate. For purposes of determining the annual emissions, the last five years of data (2006 – 2010) were reviewed. Based on the average of the highest two years in the last five years, the baseline heat input was as follows:

Unit 1 = 5.0433 x 10^{13} Btu/hr
Unit 2 = 4.7965 x 10^{13} Btu/hr

The calculated baseline emissions are:

E (Unit 1) = (5.0433 x 10^{13} Btu/yr) (0.201 lb/10^6 Btu) ÷ (2000 lb/ton)
E (Unit 1) = 5,069 tons/yr

E (Unit 2) = (4.7965 x 10^{13} Btu/hr) (0.201 lb/10^6 Btu) ÷ (2000 lb/ton)
E (Unit 2) = 4,820 tons/yr

GRE established their baseline emissions at 5,080 tons per year for Unit 1 and 5,086 tons per year for Unit 2. GRE's estimate of baseline emissions appears to be reasonable.

The Department believes the baseline emission rate should be based on 0.201 lb/10^6 Btu because:

1) Dry Fining™ (coal drying) was being installed prior to the BART decision, although no credit was taken for potential NO_x emissions reductions at that time.

2) NO_x emissions have been reduced by 0.02 lb/10^6 Btu by Dry Fining™ which will affect "anticipated" emissions which are used for establishing the baseline.

B. SNCR Control Efficiency

GRE estimated that the control efficiency of SNCR after the installation of LNC3+ will be 20%. EPA estimated that 25% control efficiency can be attained (77 FR 20919). GRE's estimate is based on a site-specific evaluation by URS. EPA's estimate is based on data from facilities other than Coal Creek Station included in the Control Cost Manual and information from Fuel Tech, Inc. and the Institute of Clean Air Companies (ICAC).

As part of the revised BART analysis, GRE supplied an EPRI report titled "Low-Baseline NO_x Selective Non-Catalytic Reduction Demonstration". The report documents the results of SNCR testing at Electric Energy's Joppa Unit 3. The results suggest that when the NO_x concentration in the flue gas is 88 ppm (day 6) or less, the removal efficiency of SNCR would be less than 15% (see Figure 3-5). However, as the NO_x concentration increases to 155 ppm to 190 ppm, the SNCR removal efficiency increased to as much at 30+%.

GRE has indicated that when CCS is operating at 0.153 lb/10^6 Btu (with LNC3+ installed), the NO_x concentration will be approximately 88 ppm (Supplemental Best Available Retrofit Technology Refined Analysis for NO_x Emissions footnote 5, p.8). Controlling NO_x emissions to such low emission rates (0.122 lb/10^6 Btu at 20% efficiency; 0.115 lb/10^6 Btu at 25% efficiency) is not well understood. EPA's Air Pollution Control Technology Fact Sheet (EPA-452/F-03-031) states "SNCR tends to be less effective at lower levels of uncontrolled NO_x. Typical uncontrolled NO_x levels vary from 200 to 400 ppm." The EPRI report states "The current project addresses the applicability of SNCR to **these low-baseline NO_x emission rates where there is currently no full-scale experience**" [emphasis added].

The study discussed in the EPRI report represents actual stack test data for a coal-fired power plant operating at an NO_x flue gas concentration similar to that at the CCS. It is not an extrapolation of data from units of varying boiler size as EPA has done in their analysis. This extrapolation does not account for the specific design features of Coal Creek Station and does not appear to include facilities with a low uncontrolled emission rate like Coal Creek Station. The Control Cost Manual does not include data for a boiler as large as either of the units at Coal Creek Station and gives no indication of the uncontrolled emission rate. The Control Cost Manual indicated larger boilers (>3,000 Btu/hr) typically have lower NO_x removal efficiencies. The boilers at Coal Creek Station are rated at more than 6,000 x 10^6 Btu/hr. The URS analysis of the expected efficiency of SNCR is based on their experience and an on-site evaluation of CCS that takes into account the existing features of the source.

The Department believes the URS estimate of 20% removal is credible and reasonable for the following reasons:

1) The EPRI report on low (≤88 ppm) uncontrolled NO_x emission rates indicates substantially less than 25% removal. With LNC3+, the NO_x emission rate at Coal Creek Station will be approximately 88 ppm.

2) The URS estimate was based on a site specific evaluation of Coal Creek Station. EPA's estimate was not.

3) The Control Cost Manual indicates SNCR will have a lower efficiency for boilers greater than 3,000 x 10^6 Btu/hr heat (CCS boilers are approximately 6,000 x 10^6 Btu/hr).

C. Capital Cost of SNCR

GRE has estimated the Installed Capital Cost (Total Capital Investment) for SNCR to be $12.18 million dollars for each unit. EPA has estimated that the capital cost to be $5,374,000 (76 FR 58620, Table 57). GRE's (URS) estimate is based on a site specific evaluation made by URS and URS software developed from actual projects. EPA's estimate uses GRE's estimate for direct capital cost and the remaining factors in the Control Cost Manual for SNCR (77 FR 58620). The major difference between the two cost estimates is a 1.6 retrofit factor used by GRE, but disallowed by EPA.

The BART Guidelines state "Once the control technology alternatives and achievable emissions performance levels have been identified, you then develop estimates of capital and annual costs. The basis for equipment cost estimated also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the *OAQPS Control Cost Manual*, Fifth Edition, February 1996, EPA 453/B-96-001). In order to maintain and improve consistency, cost estimates should be based on the *OAQPS Control Cost Manual*, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. **The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option."** [emphasis added] (40 CFR 51, Appendix Y, I.V.D., 4.5 Step 4)

To determine which estimate is more accurate, the EPA's Integrated Planning Model (IPM) methodology was used (IPM Model – Revisions to Cost and Performance for APC Technologies; SNCR Cost Development Methodology; August 2010 – see Appendix B). The IPM is a model used by EPA (and others) to analyze the project impact of environmental policies on the electric power industries in the 48 contiguous states and the District of Columbia. (see www.epa.gov/airmarkt/progsregs/epa-imp/). EPA has used this model to evaluate costs for the various NO_x BART options at the Coronado, Cholla and Apache Generating Stations in Arizona (77 FR 42852) and the Montana FIP (77 FR 24024). The documentation for the IPM cost methodology states "A retrofit factor that equates to difficulty in construction of the system **must be defined**" [emphasis added]. EPA has contended that a retrofit factor is not warranted even though the EPA Air Pollution Control Cost Manual states "The increased cost due to retrofit is approximately 10% to 30% of the cost of SNCR applied to a new boiler" (Chapter 1, Selective Noncatalytic Reduction, page 1-30). GRE contends that a retrofit factor of 60% (1.6) is appropriate. The total capital cost was calculated using the updated IPM methodology and retrofit factors of 1.0, 1.3 and 1.6. The results (adjusted to 2011 dollars) are:

Retrofit Factor	Total Capital Investment (per unit)
1.0	$10,300,000
1.3	$11,600,000
1.6	$12,800,000

With a retrofit factor of 1.0 (no increase for a retrofit), the IPM methodology predicts a cost that is about double EPA's estimated cost. With a retrofit factor of 1.6, the IPM estimates a cost that is about 5% higher than GRE's estimate. The GRE estimate using a 1.6 retrofit factor is within 30% of the IPM estimate with a retrofit factor of 1.0. An estimate with an accuracy of ±30% has the same accuracy as that provided by the Control Cost Manual (Background, Section 1.2, p.1-4).

EPA has also published an Air Pollution Technology Fact Sheet for SNCR (EPA-452/F-03-031). The fact sheet estimates that SNCR will have a capital cost of $9 - $25 per kilowatt (1999 dollars). Adjusting the cost to 2011 dollars using the Consumer Price Index yields a cost range of $12 - $34 per kilowatt. GRE's estimate is approximately $20 per kilowatt (2011 dollars). EPA's estimate is approximately $9 per kilowatt (2009 dollars) or approximately $9.4 per kilowatt in the 2011 dollars. EPA's estimate is well below the range specified in the Air Pollution Control Fact Sheet when adjusted to 2011 dollars while GRE's estimate is within the lower end of the range.

Based upon its review and consideration, the Department believes GRE's capital cost estimate is credible and reasonable for the following reasons:

1) EPA's estimate is based on the Control Cost Manual which is out-of-date.

2) Cost estimates using the IPM and EPA's Fact Sheet for SNCR suggests GRE's estimate is accurate (±30%).

3) The GRE estimate is a site specific estimate as suggested by the BART Guidelines. EPA's estimate is not site specific.

D. Reagent Usage

The amount of reagent necessary to achieve the desired NO_x reduction (0.153 lb/10^6 Btu to 0.122 lb/10^6 Btu) is a major operating cost and figures predominately in the annualized cost of SNCR. EPA has estimated that 770 lb/hr of urea (100%) would be required to achieve the required NO_x reduction. The URS estimate, based on their experience with SNCR systems, indicates that 1,155 lb/hr of urea (100%) would be required.

EPA's estimate of the amount of urea required was based on several assumptions and did not follow the methodology in the Control Cost Manual. EPA assumed a normalized stoichometric rate (NSR) of 1.0; however, based on Equation 1.14, the NSR is 1.335 (see Appendix C of the North Dakota SIP for calculation). EPA also fails to calculate a urea utilization factor in accordance with Equation 1.13 of the Control Cost Manual. Based on Equation 1.13, the utilization rate is expected to be only 15.2% (see Appendix C of the North Dakota SIP for calculation). Using Equation 1.15 in the Control Cost Manual, the amount of reagent actually reacted with the NO_x is 163 lb/hr (see Appendix C of the North Dakota SIP for calculation). With a utilization rate of 15.2%, the amount of urea actually required to be fed into the boiler is:

Urea Feed Rate = 163 lb/hr ÷ 0.152

Urea Feed Rate = 1,072 lb/hr

The urea feed rate predicted by the Control Cost Manual is much closer to GRE's estimate than it is to EPA's.

The Department further investigated the amount of urea usage by contacting Minnkota Power Cooperative. Minnkota operates an SNCR system on both units of the M.R. Young Station. Based on our investigation, GRE's predicted urea usage is reasonable when compared to Minnkota's actual usage (see Appendix C of the North Dakota SIP).

The Department also used the IPM to estimate the amount of urea required. The IPM uses default values of 1.0 for the NSR and a utilization of 15%. Using these defaults, IPM indicated 800 lb/hr of urea would be required. However, after adjusting the NSR rate to 1.335, the IPM estimated feed rate would be 1,068 lb/hr.

The Department finds GRE's estimate of urea usage to be reasonable for the following reasons:

1) The estimate is close to the estimates from the IPM and the Control Cost Manual.

2) Actual usage data from the M.R. Young Station indicates GRE's estimate is accurate.

3) EPA's estimate did not follow the procedures in the Control Cost Manual.

E. Lost Ash Sales

EPA believes no ash sales will be lost due to the operation of SNCR (77 FR 20920). Based on the Golder report, GRE expects a minimum of 30% lost ash sales and possibly 100% lost ash sales.

Golder Associates in their April 2, 2012 letter to Diane Stockdill of GRE (Appendix A - Supplemental Best Available Retrofit Technology Refined Analysis for NO_x - Appendix G) states "Based on available literature, the adsorption of ammonia onto fly ash from SNCR emission controls is highly variable and dependent upon factors such as SNCR operation, fuel type/fuel mix, boiler configuration, ash content, ash mineralogy, ash alkalinity, ash sulfur content, and temperature. Limited published data are available for ammonia levels in fly ash for coal-fired power plants utilizing SNCR emissions controls, with no published information being found for energy generation facilities burning lignite coal." The Department's research on this issue also indicated that the carbon content of the ash will also affect the amount of ammonia adsorbed on the ash. The Coal Creek Station is equipped with low-NO_x burners. Low-NO_x burners contribute to higher carbon levels in fly ash.[2]

EPA claims that the installation of ammonia slip monitoring will allow GRE to maintain ammonia slip at 2 ppm or less and ash sales will not be affected. Giampa[2] suggests that 2 ppm ammonia slip results in ammonia concentrations on the ash of approximately 100 ppm. Hinton[3], however, states "Typical ammonia-on-ash concentrations range from less than 30 ppmw to several hundred ppmw for systems experiencing ammonia slip concentrations of 2 to 5 ppmv. **Thus, some units operating with very low amounts of ammonia slip (< 1 ppmv) may experience ammonia on-ash concentrations of over 100 ppmw, while other units with relatively high ammonia slip may have ashes with very low levels of adsorbed ammonia (<50 ppmw)."** [emphasis added] For example, ammonia concentrations in fly ash at Tampa Electric's Big Bend Station vary from 750-3360 ppm, with an average concentration of approximately 2000 ppm, due to ammonia slip from an SCR system.[6] Brendel[7] et. al. reported ammonia concentrations in fly ash from seven different plants that ranged from 60-2020 ppm due to ammonia slip from SCR/SNCR systems. GRE has reported that the East Lake Station in Ohio must treat or blend 85% of their ash to make it marketable because of ammonia contamination. Fifteen percent of the ash has highly variable ammonia concentrations due to SNCR upset or plant load swings. This 15% of the ash is unmarketable because of the high ash ammonia content.

Golder Associates has indicated that ammonia levels of greater than 5 ppm (based on Headwaters'[a] experience this level is 35 ppm) can result in release of ammonia gases which impact either the sale or storage and disposal of fly ash. How much ammonia will be adsorbed on fly ash from a unit fired with North Dakota lignite is unknown. Golder Associates states "Definitive information is not available for the levels of ammonia that could be present in the fly ash at CCS due to SNCR ammonia slip."

Based upon the above, the Department believes that EPA's assertion that no ash sales will be lost is speculative. The number of factors that can affect the amount of ammonia adsorbed on the fly ash suggests that generalized statements about loss of fly ash sales are not scientifically sound. Any one facility can be different from any other facility in this regard. As the data presented above indicates, many sources have experienced high ammonia concentrations in their fly ash due to ammonia slip.

It cannot be determined, with any reasonable amount of certainty, the amount of ash sales lost due to ammonia adsorption on the ash from the operation of SNCR. However, it is reasonable to expect that changes in load, startup, shutdown and SNCR malfunctions will produce unmarketable ash. During these periods, the ammonia feed rate may have to be maintained to assure compliance with the BART emission limits which apply at all times. This could lead to higher ammonia slip. Whether an ammonia slip monitoring system can allow for an adjustment of the urea feed rate for these periods without loss of marketable ash is unknown.

III. BART Determination

A. Step 1 – Identify All Available Retrofit Control Technologies

For purposes of this reevaluation of BART, only SNCR, SNCR + LCN3+, and LCN3+ are considered viable options. Both the Department and EPA have previously determined that SCR (HDSCR, LDSCR and TESCR) and low temperature oxidation (LTO) are not required as BART. (Appendix B.2 of N.D. SIP and 76 FR 58622-58623).

B. Step 2 – Eliminate Technically Infeasible Options

All options are technically feasible.

[a]Headwaters is the marketer of the ash at the Coal Creek Station.

C. Step 3 – Evaluate Control Effectiveness

Alternative	Control Efficiency (%)	Controlled Emissions (tons/yr)		Controlled Emissions ($lb/10^6$ Btu)
		Unit 1	Unit 2	
SNCR + LNC3+	39.3	3,083	3,087	0.122
SNCR	24.9	3,816	3,821	0.151
LNC3+	23.9	3,867	3,871	0.153
Baseline	-	5,080	5,086	0.201

D. Step 4 – Evaluate Impacts and Document the Results

For purposes of the economic analysis, the average emissions reduction for the two units is used.

Unit 1				
Alternative	**Emissions Reductions (tons/yr)**	**Annualized Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
SNCR + LNC3+				
100% Lost Ash Sales	1,998	8,879,000	4,444	10,350*
30% Lost Ash Sales	1,998	6,604,000	3,305	7,449*
0% Lost Ash Sales	1,998	4,385,000	2,195	4,619*
SNCR				
100% Lost Ash Sales	1,265	9,101,000	7,194	163,471
30% Lost Ash Sales	1,265	6,826,000	5,396	118,863
0% Lost Ash Sales	1,265	4,608,000	3,643	75,373
LNC3+	1,214	764,000	629	

* Incremental cost between SNCR + LNC3+ and LNC3+.
Note: Unit 2 costs for SNCR + LNC3+ would be the same as Unit 1.

The Department is unable to determine the amount of ash that will be unmarketable because of ammonia contamination due to operation of an SNCR system. The Department believes that at least some ash sales will be lost due to startups, shutdowns, malfunctions and load changes. Recycling as much ash as possible is a goal of the Department. The use of SNCR may severely limit the achievement of that goal. Disposal of ash in a landfill also presents a potential for groundwater contamination. The operation of SNCR will also lead to the emission of ammonia to the atmosphere due to ammonia slip.

There are no other non-air quality environmental concerns that would preclude the use of any of the technologies evaluated.

E. Step 5 – Evaluate Visibility Impacts

GRE has conducted dispersion modeling to assess the potential improvement from the use of SNCR + LNC3+ and just LNC3+. The modeling was conducted in accordance with the Department's Protocol for BART-Related Visibility Impairment Modeling Analysis in North Dakota (November 2006). The Department has verified the results (see Appendix D to North Dakota's SIP). The results of that analysis are as follows:

Coal Creek Station Unit 1 or 2 (Individually) Delta Deciview 98th Percentile				
Year	**Unit**	**LNC3+**	**SNCR + LNC3+**	**Difference**
2000	TRNP-SU	0.472	0.431	0.041
2001	TRNP-SU	0.477	0.438	0.039
2002	TRNP-SU	1.040	0.936	0.104
Average	TRNP-SU	0.663	0.602	0.061
2000	TRNP-NU	0.354	0.315	0.039
2001	TRNP-NU	0.452	0.419	0.033
2002	TRNP-NU	0.910	0.804	0.106
Average	TRNP-NU	0.572	0.513	0.059
2000	TRNP-Elkhorn	0.311	0.280	0.031
2001	TRNP-Elkhorn	0.449	0.395	0.054
2002	TRNP-Elkhorn	0.795	0.711	0.084
Average	TRNP-Elkhorn	0.518	0.462	0.056
2000	Lostwood W.A.	0.428	0.415	0.013
2001	Lostwood W.A.	0.943	0.892	0.051
2002	Lostwood W.A.	0.763	0.683	0.080
Average	Lostwood W.A.	0.711	0.663	0.048
Overall Average		0.616	0.560	0.056

Coal Creek Station Unit 1 or 2 (Individually) Delta Deciview 90th Percentile				
Year	**Unit**	**LNC3+**	**SNCR + LNC3+**	**Difference**
2000	TRNP-SU	0.117	0.110	0.007
2001	TRNP-SU	0.096	0.090	0.006
2002	TRNP-SU	0.202	0.189	0.013
Average	TRNP-SU	0.138	0.130	0.008
2000	TRNP-NU	0.115	0.111	0.004
2001	TRNP-NU	0.126	0.125	0.001
2002	TRNP-NU	0.144	0.138	0.006
Average	TRNP-NU	0.128	0.125	0.003
2000	TRNP-Elkhorn	0.084	0.076	0.008
2001	TRNP-Elkhorn	0.075	0.071	0.004
2002	TRNP-Elkhorn	0.132	0.117	0.015
Average	TRNP-Elkhorn	0.097	0.088	0.009
2000	Lostwood W.A.	0.207	0.187	0.020
2001	Lostwood W.A.	0.211	0.193	0.018
2002	Lostwood W.A.	0.139	0.134	0.005
Average	Lostwood W.A.	0.186	0.171	0.015
Overall Average		0.129	0.137	0.009

The installation of SNCR will also have little effect on the number of days with a delta-deciview value above 0.5. In any year modeled (2000-2002), the number of days will decrease no more than 2 days per year at any Class I area for a single unit at Coal Creek Station and no more than 4 days per year when the two units at the station are combined.

The Department received a public comment that suggested that the LCALGRD setting in CALMET should be "True" instead of the "False" setting the Department has been using. The Department conducted modeling to evaluate the difference in the results using these two settings. The results indicate the "True" setting produces less improvement in visibility for the various control options (see Appendix D). The results shown above indicate the larger visibility improvement associated with the two LCALGRD options (LCALGRD = F).

F. Step 6 – Select BART

In making previous BART determinations, the Department gave very little weight to the single source BART-type modeling results for visibility improvement. The Department believes this type of modeling overpredicts the amount of visibility improvement by a factor of 5 to 7. Specifically, the Department's technical evaluations led it to believe that the BART type modeling overpredicts because it uses a clean background for the improvement calculation and does not account for other sources that impact visibility impairment (see North Dakota's SIP Section 7.4.2 and State of North Dakota, Comments on United States Environmental

Protection Agency Region 8, Approval and Promulgation of Implementation Plans; North Dakota Regional Haze State Implementation Plan; Federal Implementation Plan for Integrated Transport of Pollution Affecting Visibility and Regional Haze). In the case of NO_x for M.R. Young 1 and 2 and Leland Olds 2, the Department conducted cumulative type modeling and considered those results in the BART determination. Visibility results were considered in those determinations because 1) the cost effectiveness and/or incremental cost was near or slightly above the Department's cost threshold, 2) there was a wide cost effectiveness and incremental cost range, 3) the Department was aware that EPA had a different opinion on the appropriate BART (p.37 – 38, State of North Dakota, Comments on United States Environmental Protection Agency Region 8, Approval and Promulgation of Implementation Plans; North Dakota Regional Haze State Implementation Plan; Federal Implementation Plan for Integrated Transport of Pollution Affecting Visibility and Regional Haze). The Department has determined that all three of these criteria apply to the Coal Creek NO_x BART determination.

The visibility results indicate a maximum improvement in visibility of 0.106 deciviews (98th percentile) at any one Class 1 area by the use of SNCR + LNC3+ versus LNC3+. The average improvement will only be 0.056 deciviews (98th percentile). These results show there will be very little improvement in visibility. Based on the 5-7 overprediction factor previously cited, the Department believes the true visibility improvement will be 0.01 – 0.02 deciviews for the added expense associated with SNCR. Both the BART type modeling results and the estimated cumulative type modeling results indicate the amount of improvement is insignificant. This factor is not affected by the loss of ash sales. The amount of improvement in visibility, even based on the BART Guideline type modeling results, does not warrant the installation of SNCR.

When the Department began the development of the Regional Haze program in 2006, a cost threshold was established for BART controls. Any cost effectiveness above $3,650/ton or incremental cost above $6,500/ton (2006 dollars) was considered excessive (see Appendix E). If these values are adjusted to 2011 dollars based on the Consumer Price Index, any cost effectiveness above $4,100/ton or incremental cost above $7,300/ton would be considered excessive.

The Department believes that SNCR, when used alone, is clearly an inferior option to LNC3+ based on the least cost envelope analysis and the incremental cost between the two options. The incremental cost between these two options is excessive no matter whether ash sales are lost or not. The two remaining options are LNC3+ and SNCR plus LNC3+. If no ash sales are lost, the cost effectiveness and incremental cost of SNCR plus LNC3+ would be considered reasonable. However, while the Department expects some ash sales will be lost, the exact amount cannot be determined. If 30% of the ash sales are lost, the incremental cost between SNCR plus LNC3+ and LNC3+ would be considered excessive.

When EPA proposed in the FIP to disapprove the Department's BART determination for CCS, EPA's analysis of SCR at the facility indicated a cost effectiveness of $4,166/ton, an incremental cost of $6,653/ton and a visibility improvement of 0.253 deciviews (98^{th} percentile-total for two units). EPA stated "Given the anticipated visibility improvement, and the incremental cost effectiveness of $6,653, we are not prepared to impose this option as BART." The most visibility will improve by using SNCR plus LNC3+ on both units versus LNC3+ is 0.205 deciviews (total for 2 units); which is less than the amount EPA cited as a reason for rejecting SCR as BART. The Department believes that some ash sales will be lost due to startup, shutdown, malfunctions and load swings. Normal operations of SNCR can also produce high concentrations in the fly ash as noted previously. If 30% of ash sales are lost due to ammonia contamination from SNCR, the cost effectiveness will be $3,305/ton with an incremental cost of $7,449 per ton. Again, the incremental cost of SNCR plus LNC3+ versus LNC3+ is higher than SCR + SOFA + LNB versus SNCR + SOFA + LNB which EPA cited as a reason for rejecting SCR as BART.

Recycling the ash and keeping this material out of a landfill is important to the Department. The use of LNC3+ will assure that as much fly ash as possible will be recycled. The use of SNCR may prevent the recycling of any fly ash. The Department must consider the possibility of the loss of ash recycling. The loss of ash recycling is a non-air quality environmental impact that can be considered in making the BART determination (see 40 CFR 51, Appendix Y, IV.D.4 Step 4i.) due to the potential for ground water and soil contamination from the ammoniated ash. Pollution by coal ash is a significant concern of the Department and EPA. On Jun 21, 2010, EPA proposed a specific rule for the disposal of combustion residuals (including fly ash) from electric utilities (75 FR 35128 – 35264).

Over $31 million has been invested at Coal Creek Station for the management and sale of fly ash. Although EPA has indicated that this "sunk" cost cannot be taken into account in the economic analysis, the Department believes it represents an irretrievable commitment of resources for fly ash recycling and prevention of soil and water pollution. The BART Guidelines states "you may consider the extent to which the alternative emission control systems may involve a trade-off between short-term environmental gains at the expense of long-term environmental losses and the extent to which the alternative systems may result in irreversible or irretrievable commitment of resources (for example, use of scarce water resources)." If 100% of fly ash sales are lost, 31 million dollars of ash recycling equipment would be rendered useless without much chance of retrieving the resources that may prevent soil and water pollution.

In summary, the Department's NO_x BART Determination for the Coal Creek Station relies upon the following:

1) The amount of visibility improvement for SNCR + LNC3+ versus LNC3+ is very small and considered negligible. The amount of visibility improvement does not warrant the use of SNCR.

2) There is evidence that suggests to the Department that at least some ash sales will be lost and that it is reasonably possible that all ash sales will be lost. The incremental cost of SNCR + LNC3+ versus LNC3+ is excessive if 30% of fly ash sales are lost.

3) The annualized cost of SNCR + LNC3+ is excessive if 100% of ash sales are lost. The incremental cost is also excessive.

4) The loss of ash sales means landfilling of the ash which can cause other non-air quality environmental effects such as water and soil pollution.

5) The loss of ash sales will render 31 million dollars of equipment useless with likely no opportunity to retrieve the resources invested.

Because the amount of fly ash sales that will be lost cannot be exactly determined, the cost effectiveness of SNCR cannot be precisely determined. Therefore, the Department has chosen to weight the visibility impact heavily in this determination. The impact on visibility is not affected by the amount of ash sales. Therefore, the Department gave greater consideration to the fact that the use of the more expensive SNCR at CCS provides only a small amount of improvement in visibility results. Accordingly, the use of SNCR at CCS is not warranted based on the small amount of improvement in visibility that could result from its use. Additionally, the Department believes that some ash sales will be lost with the installation of SNCR, which further supports the Department's determination that SNCR at CCS is not warranted. And as detailed in this Supplemental Evaluation, there is also the potential for adverse environmental effects if ash sales are lost and that ash must be landfilled.

Based upon the analysis set forth in this Supplemental Evaluation, the Department accordingly reaffirms its decision that NO_x BART for the GRE CCS is represented by combustion controls with a BART limit of 0.17 lb/10^6 Btu on a 30-day rolling average basis.

References

1. Sargent & Lundy; IPM Model – Revisions to Cost and Performance for APC Technologies; SNCR Cost Development Methodology – Final; August 2010.

2. Giampa, Vincent M.; Ammonia Removal from Coal Fly Ash by Carbon Burn-out.

3. W.S. Hinton & Associates; Fly Ash Behavior

4. 40 CFR 51, Appendix Y; Guidelines for BART Determinations under the Regional Haze Rule.

5. EPA Air Pollution Control Cost Manual; Sixth Edition; EPA/452/B-02-001; January 2002.

6. Bittner, James D.; Gasiorowski, Stephen A.; Hrach, Frank J.; Fly Ash Carbon Separation and Ammonia Removal at Tampa Electric Big Bend; 2009 World of Coal Ash Conference; May 2009.

7. Brendel, G.F.; Bonetti, J.E.; Rathbone, R.F.; Frey, R.N., Jr.; Investigation of Ammonia Adsorption on Fly Ash Due to Installation of Selective Catalytic Reduction Systems; Final Technical Report; DOE Award No. DE-FC26-98FT 400 28; November 2000.

Appendix A
GRE BART Analysis

Appendix B
IPM Documentation and Results

Appendix C
Memo to Regional Haze File
Reagent Usage

Appendix D
NDDH Visibility Results

Appendix E
BART Costs

Appendix F
Correspondence Regarding
BART Determination